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The role of static and dynamic modeling in the Fort Nelson CCS Project

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Abstract

Spectra Energy Transmission and the Energy & Environmental Research Center, through the Plains CO_2 Reduction Partnership, are investigating potential commercial-scale carbon capture and storage in a saline formation near Fort Nelson, British Columbia, Canada, by conducting detailed modeling and predictive simulations of injection at the Fort Nelson site. The results of the Fort Nelson modeling activities are providing insight regarding the movement of sour CO_2; the potential effects that large-scale sour CO_2 injection may have on neighboring natural gas production fields; and the deployment of selected monitoring, verification, and accounting techniques.

Keywords: CO_2 storage; dynamic modeling workflow; reservoir simulation; risk assessment

1. Introduction

Spectra Energy Transmission (SET) and the Plains CO_2 Reduction (PCOR) Partnership, led by the Energy & Environmental Research Center, are investigating the feasibility of a carbon capture and storage (CCS) project to mitigate carbon dioxide (CO_2) emissions from SET's Fort Nelson Gas Plant (FNGP). The FNGP and the proposed CO_2 storage area are located near the town of Fort Nelson in northwestern British Columbia, Canada, as shown in Figure 1 [1]. This waste gas stream produced by the FNGP from natural gas processing includes up to 5% hydrogen sulfide (H_2S) and a small amount of methane (CH_4). As such, it is referred to as a "sour" CO_2 stream. The sour CO_2 gas stream would be injected into a deep saline carbonate formation for the purpose of long-term storage. The Fort Nelson

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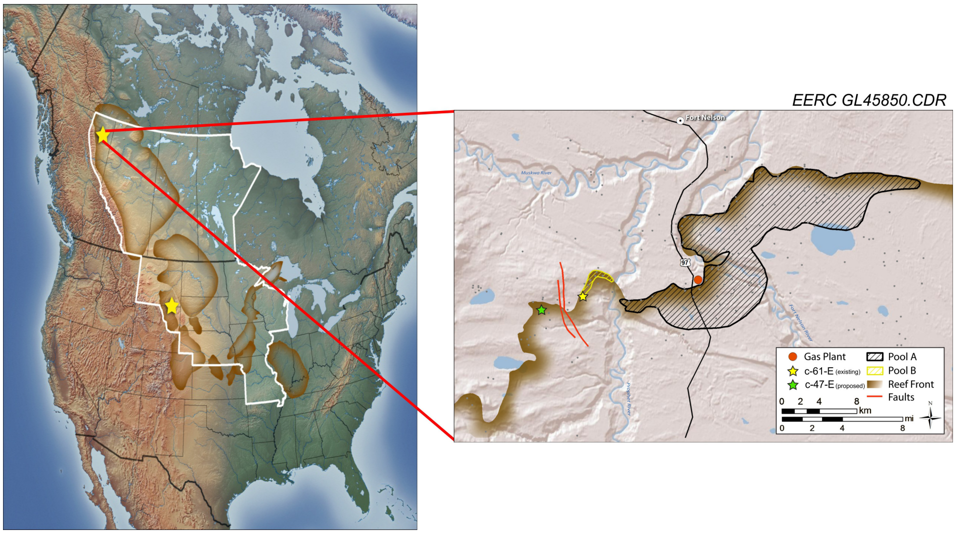

Fig. 1. Site location with white outline of the PCOR Partnership region (left) and study area map (right)

demonstration project provides a unique opportunity to develop a set of cost-effective, risk-based monitoring, verification, and accounting (MVA) protocols for large-scale (>1 million tonnes a year) storage of sour CO_2 in a deep saline formation. The likely injection target will be a carbonate formation in the Devonian Presqu'ile reef complex, with the 500-m-thick shales of the overlying Muskwa and Fort Simpson Formations serving as seals. The effectiveness of the MVA activities will be at least partially dependent on developing a thorough geologic characterization, modeling, and risk assessment effort. The results of the Fort Nelson activities will provide insight regarding 1) the behavior of sour CO_2 in a deep brine-saturated carbonate reservoir environment; 2) the impact of sour CO_2 on the integrity of sink and seal rocks; 3) the effects of large-scale sour CO_2 injection and storage on wellbore integrity; 4) the effectiveness of selected MVA techniques; and 5) the use of an approach that combines iterative geologic characterization, modeling, risk assessment, simulation, and MVA planning to safely and cost-effectively inject and store large volumes of sour CO_2. The role of the PCOR Partnership is to provide the project with reservoir modeling and simulation, risk assessment of subsurface technical risks, and an MVA plan to address these risks. The PCOR Partnership applies a philosophy of integration that combines geologic characterization, modeling, risk assessment, and MVA strategies into an iterative process to produce superior-quality results during the project feasibility and development periods.

2. Method

The method used in this study is an integrated, iterative, risk-based approach for defining MVA strategies (Figure 2). Site characterization, modeling and simulation, risk assessment, and the development of a cost-effective MVA plan are the four key components iterated during the course of a CCS project. This approach will be applied through the feasibility, design, injection, closure, and postclosure periods of the project. Each iteration will improve the technical and cost-effectiveness of the MVA plan, while simultaneously reducing project risks.

The focus of this paper is the modeling components of the project. Static and dynamic modeling play a crucial role during each iteration of the risk-based MVA strategy used for the Fort Nelson CCS Project.

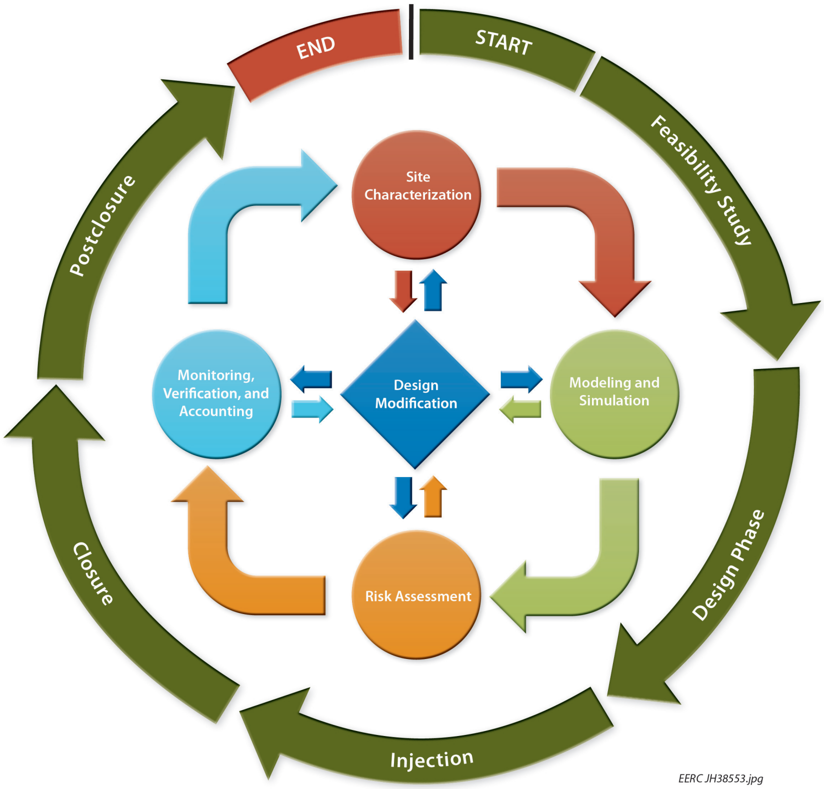

Fig. 2. Risk-based MVA approach [1]

In order to more effectively integrate the modeling and simulation into the overall MVA strategy, a dynamic modeling workflow was developed (Figure 3) [1]. The workflow utilizes three techniques: 1) grid-size sensitivity analysis, used to create the coarsest grid resolution that will yield accurate results; 2) numerical tuning to speed up simulation run time and minimize materials balance error; 3) properties/parameters sensitivity analysis to identify the properties and parameters that have the greatest effect on the simulation results. The optimized model is then validated by history matching to obtain a reasonable match between simulated results and historical data before running any predictive CO_2 simulations [1].

After the model optimization and validation were completed, predictive simulations were run to determine fluid migration and pressure propagation. This information was then used as a basis for a subsurface technical risk assessment. Through the course of running the predictive simulations and risk assessment, areas of additional characterization and potential risk were identified, leading to several additional iterations of the risk-based MVA approach.

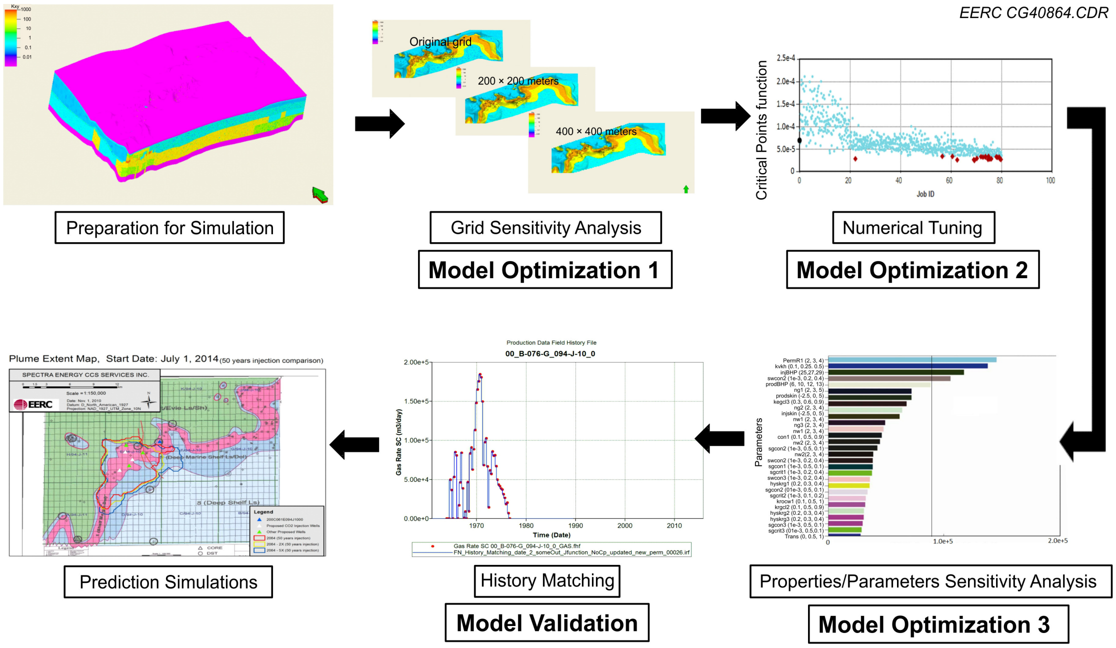

Fig. 3. Dynamic modeling workflow

3. Results and discussions

History matching

A history-matching process was used to improve modeled outputs and to obtain a good match with historical data, which demonstrates the ability of the model to accurately predict reservoir conditions. A total of 92 wells were utilized, including 85 production wells and 7 water disposal wells in the study area, primarily in Gas Pools A and B (Figure 1). The goal of this step is to match gas and water production, water disposal, and well bottomhole pressure (BHP). Ultimately, by matching these parameters in the nearby gas pools, a more accurate geological model with a current matched distributed regional pressure profile could be used. After 494 history-matching simulation runs, an asymptotic convergence was achieved with a total of 92 wells matched (Figure 4A). Upon convergence, the global objective function error between the simulation runs and the historical data is 3.91% (Figure 4B). Correspondingly, Figures 4C and 4D show a comparison of the historical and simulation data for cumulative gas production and cumulative water disposal. These history-matching results indicate a good match for gas and water production, water disposal, and BHPs for all wells in the investigated area.

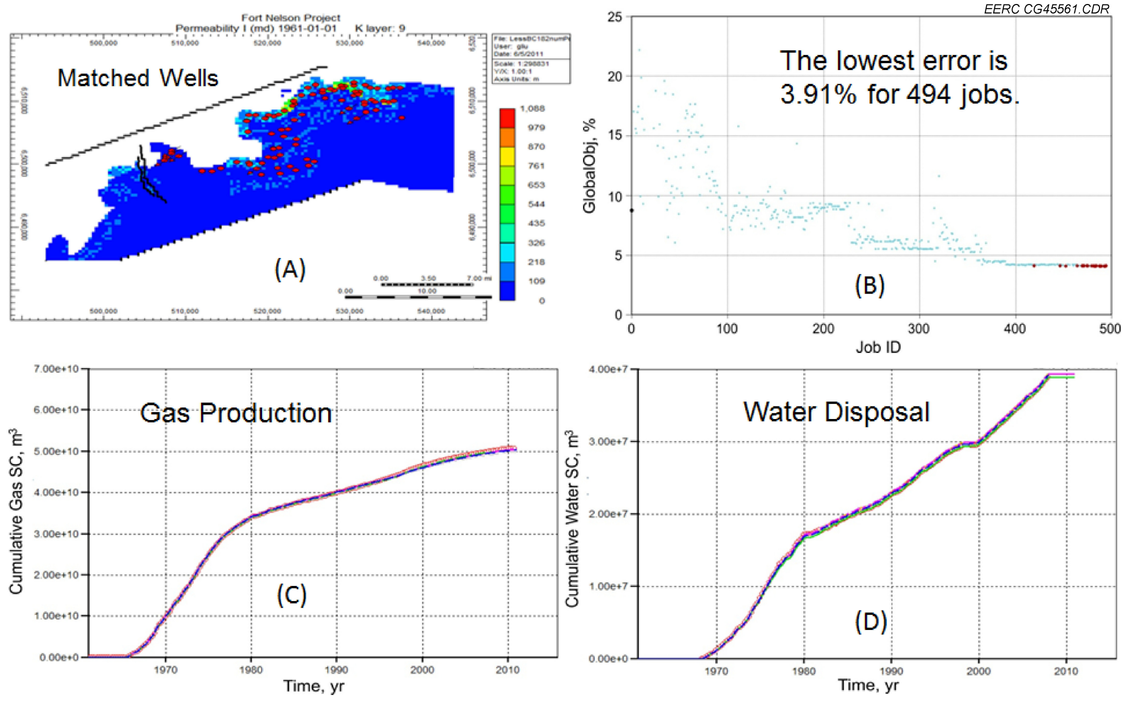

Fig. 4. History-matching results: (A) matched 92 wells; (B) global objective function error for 494 simulation jobs; (C) cumulative gas production; and (D) cumulative water disposal based on the top five “best”-matching cases (SC is standard conditions: 15.5°C, 101.25 kPa)

The fieldwide distributions of the initial pressure (before history matching) and the measured pressure (January 2011) are shown in Figure 5A and 5B, respectively. The simulated pressure distributions obtained after history matching were replicated by introducing boundary settings and a lower-permeability barrier between Gas Pools A and B to mimic the observed trends in the historical data [1]. The overall field pressure matches throughout the transient region between gas pools and the injection region with a few small deviations (Figure 5C).

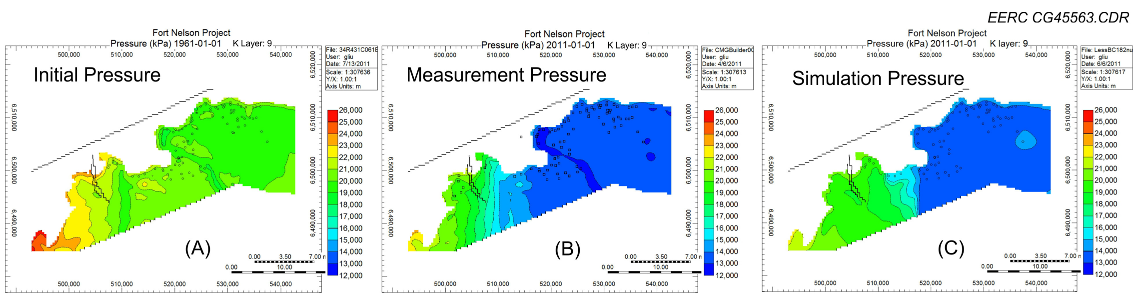

Fig. 5. Pressure distributions: (A) initial pressure distributions; (B) measured pressure distributions (January 2011); (C) matched pressure distributions

3.2 Predictive simulations around Test Well c-61-E

Once the geological model was matched to the historic production and injection in the nearby gas fields, predictive simulations were run to investigate CO_2 and pressure movement in and around Test Well c-61-E. Sour CO_2 was injected in Test Well c-61-E and two other locations (Track 1) in the immediate vicinity at a combined rate of 3.4 MMm^3/day (120 MMscf/day) for 25 years (Figure 6). The simulations were run for a total of 100 years, with 75 years of postinjection to address CO_2 movement and reservoir pressure buildup. The results in Figure 7 show the distributions of the injected CO_2 (in gas/unit area) over time, which includes the status of preinjection, at the end of CO_2 injection (25 years cumulative time), 25 years of postinjection (50 years cumulative time), and 75 years of postinjection (100 years cumulative). These simulation results indicate that the CO_2 may reach both of the gas pools within the 100-year period. After these simulations were run, a quantitative risk assessment was performed. The risk assessment indicated that the possibility of contacting the nearby gas pools required further geological characterization between the proposed injection locations and the gas pools. In addition, an alternative injection location further to the west would help reduce this risk of contacting the gas pools. An alternative injection location, combined with integrated activities such as additional site characterization, drilling a second test well, new seismic acquisition data, and model validations, is needed to reduce the potential risk around the c-61-E location or the proposed location (c-47-E) further to the west.

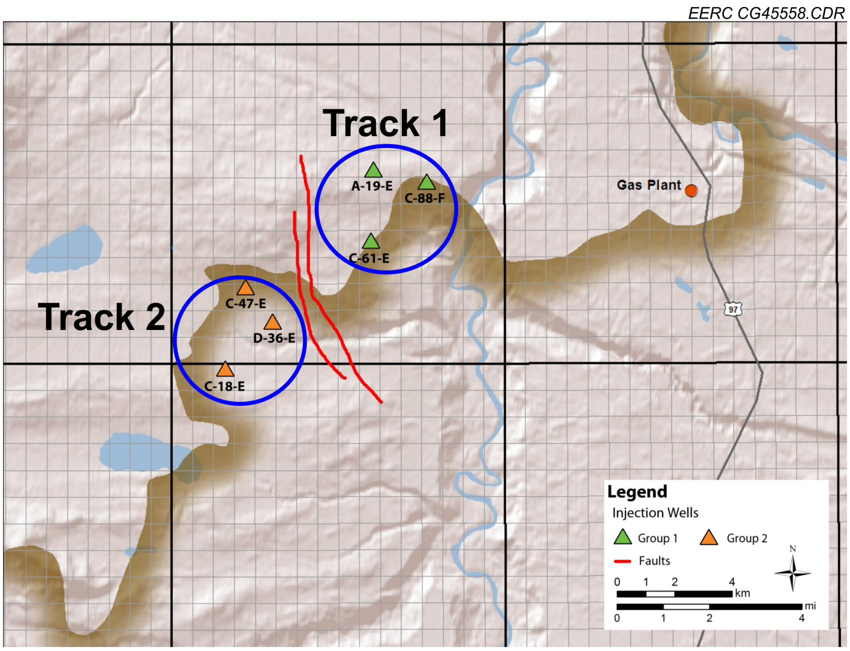

Fig. 6. Location of tracks and injection wells

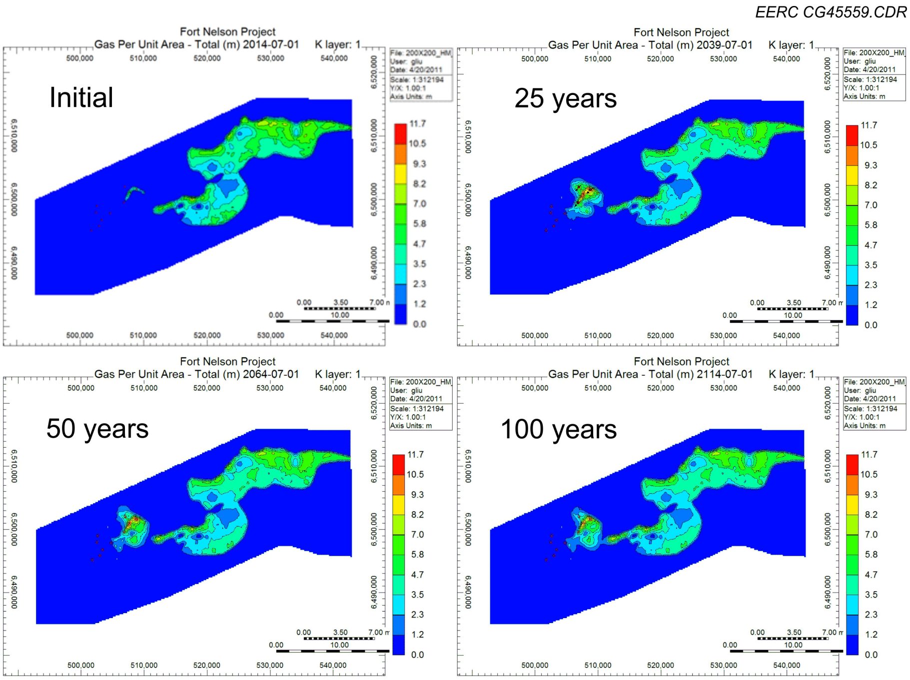

Fig. 7. CO_2 movement over time around Test Well c-61-E

3.3 Alternative CO_2 injection location

The results of initial risk assessment around Test Well c-61-E suggested that the injection location should move 5–10 kilometers southwest, around the proposed well, c-47-E (Track 2), to avoid the communications between injected CO_2 and gas pools (Figure 6). In Track 2, 1.1 MMm^3/day (40 MMscf/day) was injected into three wells, including the new proposed well, c-47-E, for a combined sour CO_2 injection rate of 3.4 MMm^3/day (120 MMscf/day) for 25 years, with an additional 75 years of postinjection simulation, for a total of 100 years simulated.

The predictive simulation results in Track 2 indicate that the CO_2 plume does not contact the nearby gas pools during the 100-year simulation period (top of Figure 8). When comparing the two injection and risk tracks, injection in and around Track 2 greatly reduces the likelihood of sour CO_2 contacting either gas field; however, there is greater uncertainty in the geology in that region because there are few to no seismic or well data. In Track 1, there is a possibility that sour CO_2 may contact one or both of the nearby gas fields before the end of the productive life of either field. However, there is still a large degree of geologic uncertainty between Track 1 and the gas fields. In addition, the BHPs based in the injection wells in Track 2 are 1000 to 3000 kPa lower than the BHPs in the Track 1 injectors (Figure 9). While Track 1 shows a lower overall risk profile, there is a large degree of geologic uncertainty in that region, which requires further investigation.

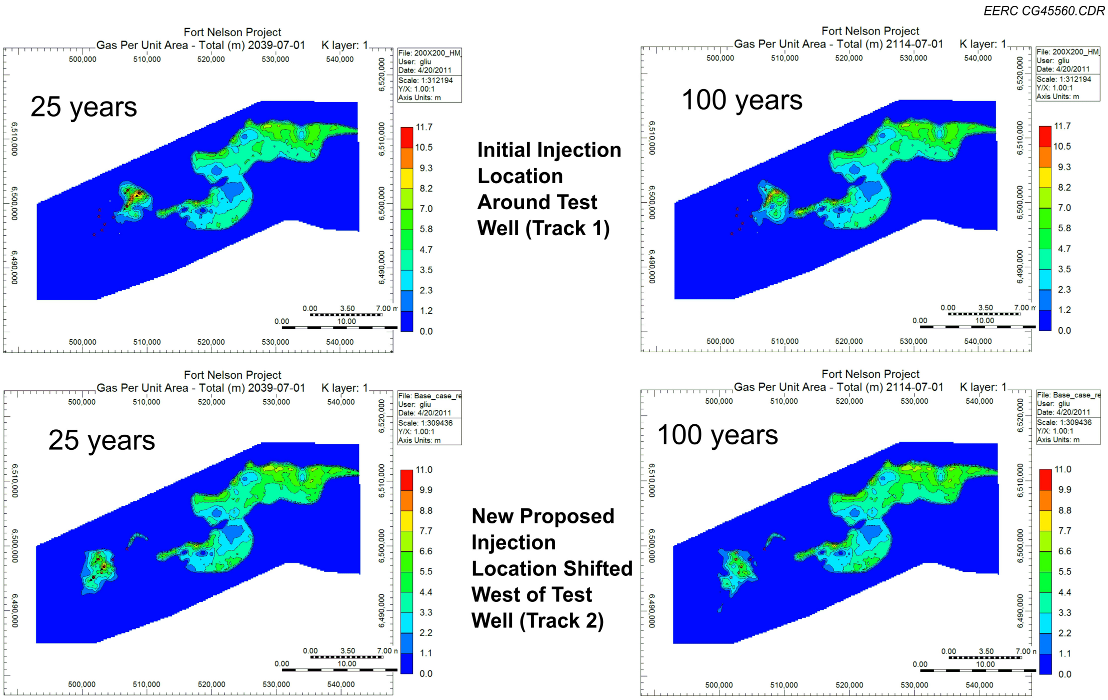

Fig. 8. Gas per unit area over time for two tracks. Track 1 is based on Test Well c-61-E after history matching (top), and Track 2 is based on Well c-47-E (bottom)

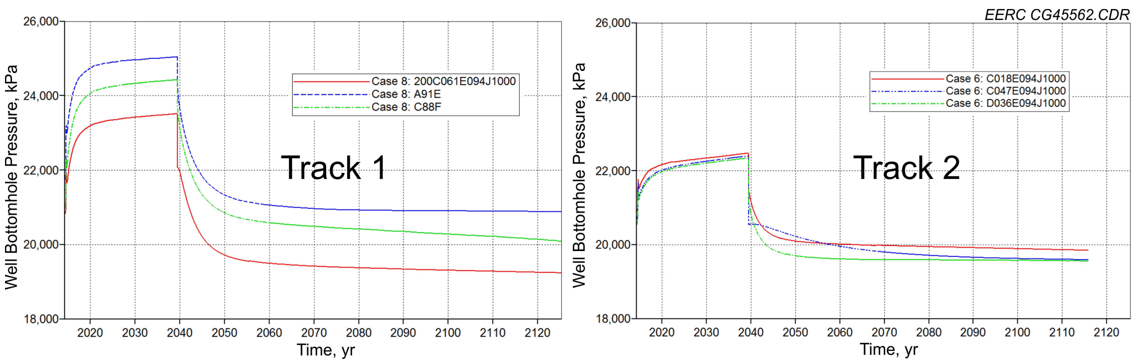

Fig. 9. BHP plots by each injection well, in tracks. Track 1 is on the left, and Track 2 is on the right

4. Conclusion and future work

The static and dynamic modeling in the Fort Nelson CCS Project plays a crucial role in predicting the movement of sour CO_2 in the reservoir, informing the risk assessment, and helping to define and develop the MVA plan. The proposed dynamic modeling workflow, along with the integrated approach to site characterization, modeling, and risk assessment, can lead to a more targeted, site-specific, and technically and economically feasible MVA plan and CCS project.

Both injection locations (Track 1 and Track 2) appear to have sufficient capacity to accommodate the target injection volumes. However, current knowledge suggests that Track 2 may be a better option (compared to Track 1) because the injected sour CO_2 has a more contained CO_2 footprint and does not contact the adjacent gas pools during the 100-year simulation period. In addition, the injection well BHPs in Track 2 were predicted to be 1000 to 3000 kPa lower than the injection well BHPs in Track 1. Overall, Track 2 has a lower risk profile; however, the collection of 3-D seismic data and the drilling of an additional well in the vicinity of Track 2 are necessary to determine whether or not the geology is suitable for the injection of 3.4 MMm^3/day (120 MMscf/day) for 25 years.

Future work includes the development of an MVA plan for both Track 1 and Track 2 based on the results of the site characterization, modeling and simulation, and risk assessments. This MVA plan will be updated along with the modeling and simulation and risk assessment once additional site characterization activities are completed.

Acknowledgements

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Disclaimer

Reference

[1] Gorecki C, Sorensen J, Klapperich R, Botnen S, Steadman E, Harju, J. A risk-based monitoring plan for the Fort Nelson feasibility project. SPE Paper 151349-MS, presented at the Carbon Management Technology Conference, Orlando, Florida, USA, Feb 7–9, 2012.